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April 18, 2016

Mr.Guy R. Donaldson
U.S. Environmental Protection Agency – Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733
donaldson.guy@epa.gov

Re: Submittal of March 18th 2016 Revised BART Five-Factor Analysis

Dear Mr. Donaldson:

As mentioned in the Revised BART Five-Factor Analysis that was submitted to you on April 15th 2016, the execution of one CALPUFF modeling scenario was not completed in time for submittal and so the document was marked as "PRELIMINARY". It was also stated that the FFA report would be resubmitted upon completion of the final modeling scenario. Enclosed is the revised document. All the values marked "TBD" in the tables of the preliminary revised FFA have been replaced with numerical values.

Thank you for your consideration of this supplemental information. Please contact me with any questions or concerns.

Sincerely,

Bill Matthews

Bill Matthews
Director - Environmental Policy and Planning

Enclosures

cc: Vivian Aucoin, LDEQ (vivian.aucoin@la.gov)
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Jeremy Jewell, Trinity Consultants (jjewell@trinityconsultants.com)

Cleco Corporation
Brame Energy Center

CLECO

BART Five-Factor Analysis

Submitted to:

Louisiana Department of Environmental Quality (LDEQ)
Air Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

and

U.S. EPA Region 6, 6PD-L
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October 31, 2015, *Revised April 15, 2016 and April 18, 2016*

Project 153701.0033

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) as proposed for Cleco Corporation's (Cleco's) BART-affected electric generating units (EGUs) at Brame Energy Center (Brame) in Rapides Parish, Louisiana (LA) based on CALPUFF modeling done thus far. Cleco reserves the right to supplement this report with additional analyses.

Cleco operates two BART-affected EGUs at Brame:

- Nesbitt I (Unit 1) is a 440-megawatt (MW) EGU boiler that burns natural gas[1] and is not equipped with any air pollution control devices (APCDs).

- Rodemacher II (Unit 2) is a 523-MW wall-fired EGU boiler that burns Powder River Basin (PRB) coal. Cleco has recently made several changes that reduce emissions at Unit 2.
  - Low-NO_X Burners (LNB) were installed in 2008;
  - Low-sulfur fuel began to be burned in 2009;
  - Selective non-catalytic reduction (SNCR) was installed in 2014 for complying with ozone season NO_X requirements of Cross-State Air Pollution Rule (CSAPR); and
  - Dry sorbent injection (DSI), activated carbon injection (ACI) and fabric filter (FF) were installed in 2015 for compliance with the Mercury and Air Toxics Standard (MATS).

Unit 1 was listed among the twelve BART-affected sources in the LA Regional Haze State Implementation Plan (SIP).[2] Unit 2 was not previously listed as a BART-affected source in the SIP, but was determined later to be a BART-eligible source. In response to EPA's Section 114 request,[3] Cleco submitted a BART-applicability screening analysis (Screening Analysis Report) to Louisiana Department of Environmental Quality (LDEQ) and Environmental Protection Agency (EPA) Region 6 on August 31, 2015. Based on the CALPUFF-based screening analysis presented in that report, Brame Units 1 and 2 were determined to be BART-affected emission units.[4] Therefore, this document presents the BART Five-Factor Analysis for each emissions unit.

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[1] Unit 1 is currently also permitted to combust oil, but it has not in several years, and, due to the Mercury and Air Toxics Standards (MATS) rule, will not combust oil in the future.

[2] LDEQ, Louisiana Regional Haze SIP, June 2008: http://www.deq.louisiana.gov/portal/DIVISIONS/AirPermitsEngineeringandPlanning/AirQualityPlanning/LouisianaSIPRevisions/LouisianaRegionalHazeSIP.aspx

[3] Wren Stenger, Section 114(a) Information Request letter to Darren Olagues (Cleco), May 19, 2015.

[4] Following the August 31, 2015 submittal, Cleco conducted an updated screening analysis using the Comprehensive Air Quality Model with Extensions (CAMx) modeling system. This analysis demonstrates that the visibility impacts from each of the Cleco BART-eligible sources are well below the EPA's recommended screening threshold of 0.5 deciview (dv) at both the Breton Wilderness Area (Breton) and Caney Creek Wilderness Area (Caney Creek). Further, the cumulative impact of all Cleco BART-eligible sources in Louisiana based on CAMx modeling is well below the 0.5 dv screening threshold at Breton and Caney Creek. As such, Cleco's BART-eligible sources are not reasonably anticipated to "cause" or "contribute" to visibility impairment at any Class I area and are therefore not subject to BART.

The BART guidelines[5] states that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

EPA's BART Guidelines in 40 CFR Part 51[6] were used to determine BART for the boilers. The Guidelines specify the following five-step analysis to determine BART:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

Based on these steps, considering the five factors listed above, Cleco has determined BART as follows:

- SO_2 – Unit 1 natural gas only and enhanced DSI for Unit 2.
- NO_X –The requirements of CSAPR satisfy BART for NO_X emissions from Unit 1 and Unit 2.
- PM_{10} – No additional controls constitute BART.

[5] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005.

[6] Ibid.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background. Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *"...an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by...[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonable be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts

A BART determination should be made for each visibility affecting pollutant (VAP) by following the five steps listed above.

Brame Units 1 and 2 meet the three BART-eligibility criteria described on the previous page, and therefore, a CALPUFF-based screening analysis was conducted for determining BART-applicability. The results of this modeling was presented in the August 31, 2015 Screening Analysis Report, and the results indicate that the Brame affected source is reasonably anticipated to cause or contribute to visibility impairment. As such, a BART five-factor analysis for each Brame unit is presented in this report.

The details of the Brame Unit 1 and Unit 2 existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by Unit 1 and Unit 2 include NO_x, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particle matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The proposed BART determinations for SO_2, NO_x, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

3. MODELING METHODOLOGIES AND PROCEDURES

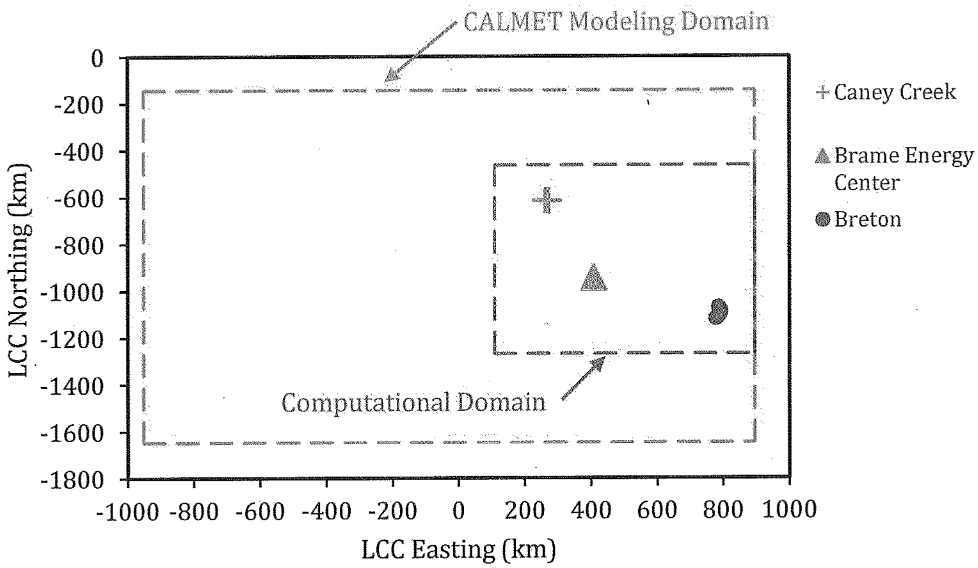
The modeling methodologies and procedures utilized in the October 31, 2015 BART Five-Factor Analysis were followed with one exception: the computational domain was extended such that a 150 km buffer surrounded the modeled sources and Class I receptors. This modeling change was made at the request of EPA in their letter to Cleco regarding their preliminary review of the October 31, 2015 BART Five-Factor Analysis.[7]

MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion.

A plot of the meteorological modeling domain for the existing CENRAP CALMET dataset with respect to Cleco's BART-affected sources and the Class I areas being modeled is provided in Figure 3-1. The computational domain was modified such that it extends at least 150 km to the north, west, and south of Brame Unit 1, Unit 2, and the Class I areas of interest. The eastern boundary of the computational domain was extended as far as the CALMET dataset would allow, i.e., 130.8 km from the eastern-most source/receptor.

Figure 3-1. Refined Meteorological Modeling Domain



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[7] Letter from Guy Donaldson (EPA Region 6) to Bill Matthews (Cleco), March, 16, 2016. Re: Preliminary review of BART Determination. As requested in this letter, the computational domain was adjusted to be consistent with the EPA-approved screening modeling done by Sid Richardson.

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e., baseline) visibility impairment attributable to Brame Unit 1 and Brame Unit 2 based on CALPUFF-based air quality modeling conducted by Trinity.

NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the maximum 24-hour emission rates that were modeled for SO_2, NO_x, and PM_{10}, including the speciated PM_{10} emissions. Baseline emission rates for Unit 1 (all pollutants) and Unit 2 NO_X and PM_{10} reflect emissions from the original baseline period of 2000-2004 that was presented in Cleco's Screening Analysis Report. The baseline SO_2 emission rate for Unit 2 was adjusted to reflect recent (2010-2014) operation with low-sulfur fuel in accordance with the BART Guidelines.[8] The result of updating the baseline is less than a 1.5 % decrease in modeled SO_2 emission rate. Again, Unit 2 emission rates for NO_X and PM_{10} remain the same as presented in the Screening Analysis Report.

Table 4-1. Baseline Emission Rates

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Brame, Unit 1	3,354.62	1,321.50	245.00	54.88	48.93	121.77	9.68	9.73
Brame, Unit 2	5,415.00	3,298.63	189.60	0.00	89.57	69.01	28.37	2.65

Brame Unit 1

The SO_2, NO_x, and PM_{10} emission rates for Brame Unit 1 were obtained from the previously submitted LA SIP[9,10] and reflect 2000-2004 emissions. Speciated PM_{10} emission rates shown in Table 4-1 reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) "speciation spreadsheet" for *Uncontrolled Utility Residual Oil Boilers.*[11] More specifically, the NPS workbook shows the following baseline distributions for the PM species from No. 6 fuel oil for Unit 1:

- Coarse PM (PMC) = 20.0%
- Fine soil (modeled as PMF) = 49.7%
- Fine elemental carbon (modeled as EC) = 4.0 %
- Organic condensable PM (modeled as SOA) = 4.0%

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[8] 40 CFR Part 51, Appendix Y, Section IV.D.4.c: *The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.*

[9] Brame Unit 1 was formerly known as Rodemacher Power Station, and was referred to as such in the LA SIP.

[10] LDEQ. LA Regional Haze SIP, Table 9.2: BART-eligible facilities closest to Caney Creek

[11] Unit 1 PM speciation is based on NPS Workbook, "Uncontrolled Utility Residual Oil Boiler.xls", #6 oil with a sulfur content of 0.304%, and a heat input capacity of 5,004 MMBtu/hr. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm

- Inorganic condensable PM (modeled as SO4) = 22.4%

Brame Unit 2

The NO_x emission rate was obtained from EPA's Clean Air Markets Division (CAMD) database and reflects the highest actual 24-hour emission rates from 2000-2004 continuous emissions monitoring system (CEMS) data. The SO_2 emission rate (updated) is based on the highest daily emission rate (0.95 lb/MMBtu) and the highest heat input from 2010-2014 CEMS data. Total PM_{10} emission rates for Brame Unit 2 are based on 2014 stack test data. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12]. Specifically, the NPS workbook shows the following baseline distribution for the PM species:

- Coarse PM (PM_C) = 47.2 %
- Fine soil (modeled as PM_F) = 36.4 %
- Fine elemental carbon (modeled as EC) = 1.4 %
- Organic condensable PM (modeled as SOA) = 15.0 %
- Inorganic condensable PM (modeled as SO_4) = 0 %

An SO_4 emission rate was independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] This SO_4 rate was used in the modeling instead of the rate resulting from the NPS-based breakdown.

BASELINE VISIBILITY IMPAIRMENT

Based on the emission rates presented in Table 4-1, Trinity conducted CALPUFF modeling to determine the baseline visibility impairment attributable to Brame Unit 1 and Unit 2, and in two Class I Areas: Caney Creek Wilderness (CACR) and Breton National Wildlife Refuge (BRET).

Table 4-2 and Table 4-3 provide a summary of the modeled visibility impairment for the refined baseline attributable to Brame Units 1 and 2 at CACR and BRET. Note that all of the CALPUFF, POSTUTIL, and CALPOST modeling files are included as part of the electronic files submitted with this document.

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[12] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 189.6 lb/hr, heat value of 8,757 Btu/lb, sulfur content of 0.45%, ash content of 5.5%.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-2. Baseline Visibility Impairment Attributable to Brame Unit 1

Year[1]	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness						
2001	0.379	4	0.321	0.053	0.005	0.000
2002	0.372	5	0.152	0.199	0.015	0.007
2003	0.430	5	0.335	0.079	0.013	0.003
Breton						
2001	0.401	4	0.292	0.103	0.006	0.000
2002	0.157	0	0.119	0.032	0.004	0.002
2003	0.410	3	0.317	0.086	0.007	0.000

[1] Meteorological data year modeled.

[2] Model results reflect the revised CALPUFF run with computational domain extended by 150 km.

Table 4-3. Baseline Visibility Impairment Attributable to Brame Unit 2

Year[1]	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness						
2001	0.689	14	0.520	0.164	0.005	0.000
2002	0.689	13	0.181	0.478	0.012	0.018
2003	0.734	18	0.489	0.235	0.010	0.000
Breton						
2001	0.677	10	0.366	0.305	0.006	0.001
2002	0.290	2	0.065	0.211	0.004	0.011
2003	0.724	13	0.519	0.197	0.008	0.000

[1] Meteorological data year modeled.

PROPOSED BART FOR SO_2 FOR UNIT 1

Brame Unit 1 burns natural gas and is permitted to combust oil, but it has not in several years, and, due to the MATS rule, will not combust oil in the future. A BART determination for SO_2 based on the use of natural gas only was approved in EPA's March 12, 2012, final rule in Arkansas. The determination resulted in no SO_2 controls needed during natural gas combustion.[14] Cleco proposes the same determination for Brame Unit 1. The potential to emit under this scenario is 3.0 lb/hr.[15]

IDENTIFICATION OF AVAILABLE RETROFIT CONTROL TECHNOLOGIES FOR UNIT 2

Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Brame Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 will further reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Brame Unit 2 are summarized in Table 5-1. The retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as Unit 2 currently uses a low sulfur fuel and thus would not achieve significant additional reductions through alternative fuel supplies comparable to the most efficient add-on controls. The available SO_2 control technologies are Dry Sorbent Injection (DSI), enhanced DSI, semi-dry scrubbing, and wet scrubbing.

Table 5-1. Available SO_2 Control Technologies for Unit 2

SO_2 Control Technologies
Dry Sorbent Injection
Enhanced Dry Sorbent Injection
Dry / Semi-Dry Scrubbing, e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing

ELIMINATE TECHNICALLY INFEASIBLE CONTROL TECHNOLOGIES FOR UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

[14] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

[15] Based on the SO_2 emission factor, 0.0006 lb/MMBtu, from AP-42 Section 1.4 (7/98) and the unit's maximum heat input capacity, 5,004 MMBtu/hr.

Dry / Semi-Dry Scrubbing

There are various designs of dry or semi-dry scrubbing, or fuel gas desulfurization (FGD), systems, the most popular of which is the Spray Dryer Absorber (SDA) designs. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

Based on a site-specific study completed by Sargent & Lundy, SDA could achieve an SO_2 outlet emission rate of 0.06 lb/MMBtu at Brame Unit 2. [16]

Wet Scrubbing

Wet scrubbing, or wet flue gas desulfurization (WFGD), involves scrubbing the exhaust gas stream with slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an ESP to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similar to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Based on a site-specific study completed by Sargent & Lundy, WFGD could achieve an SO_2 outlet emission rate of 0.04 lb/MMBtu.[17]

Dry Sorbent Injection

Dry sorbent injection (DSI) involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was developed as a lower cost flue gas desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower. This technology is currently employed for the control of HCl from Unit 2 and also achieves a co-benefit of nominal SO_2 control at an efficiency of approximately 39 %.

Enhanced DSI

To evaluate the additional removal of SO_2 that the existing DSI system is capable of achieving, Sargent & Lundy reviewed the SO_2 emissions data recorded during two HCl performance tests where higher Trona injection rates were used. The first test was performed while injecting Trona at a rate of 12,000 lb/hr. This test showed an average SO_2 removal efficiency of 66 %. However, during this performance test, mercury emissions were elevated; this could potentially be attributed to the interference between Trona and activated carbon. Subsequently, a second performance test was completed with a lower Trona injection rate of 4,000 lb/hr. MATS compliance was achieved during this test along with an average SO_2 removal efficiency of 63 %.

Based on these tests, it can be seen that very limited additional SO_2 reduction is achievable at injection rates greater than 4,000 lb/hr; increasing the injection rate by 300 % only provided an additional 3 % SO_2 reduction

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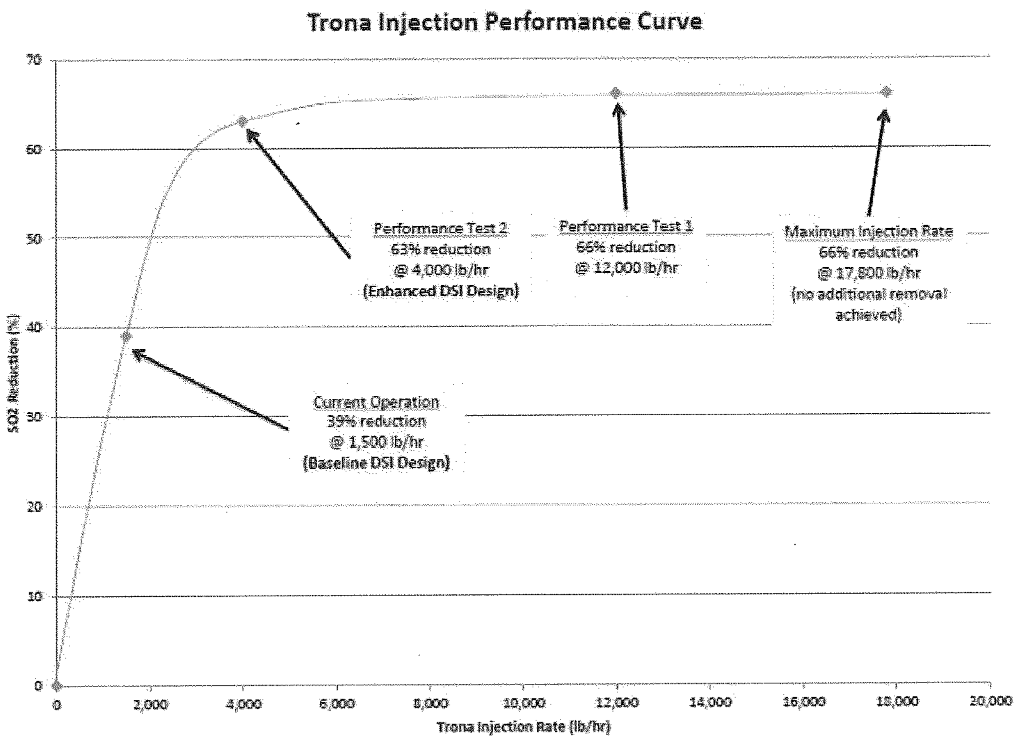
[16] 0.06 lb/MMBtu is consistent with vendor-specified rates for calculating potential emissions reductions; however, S&L recommends that a rate of 0.08 lb/MMBtu is more appropriate for establishing an enforceable limitation for DFGD.

[17] 0.04 lb/MMBtu is consistent with vendor-specified rates for calculating potential emissions reductions; however, S&L recommends that a rate of 0.06 lb/MMBtu is more appropriate for establishing an enforceable limitation for WFGD.

on average. The DSI system performance is plotted in Figure 5-1. Based on the review completed by Sargent & Lundy, the DSI system at Unit 2 can be enhanced to achieve an outlet emission rate of 0.30 lb/MMBtu on an annual-average basis.

Figure 5-1. DSI Performance Curve[18]



[18] Provided by Sargent & Lundy, LLC for Cleco's Rodemacher II.

RANK OF TECHNICALLY FEASIBLE CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing the VAP. Table 5-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 5-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu)[19]
Wet Scrubber (WFGD)	0.04
Semi-Dry Scrubber (DFGD)	0.06
Enhanced Dry Sorbent Injection w/Fabric Filter	0.30
Dry Sorbent Injection w/Fabric Filter	0.41

EVALUATION OF IMPACTS FOR FEASIBLE CONTROLS FOR UNIT 2

The fourth step in the BART analysis is the impact analysis where the impacts for those control options deemed feasible in Step 2 are evaluated. This analysis is typically conducted to demonstrate that a control technology that is more effective than another technology does not constitute BART. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

Cost of Compliance

The capital costs, annualized capital costs, and annual operating and maintenance costs for the considered control options were developed by Sargent & Lundy. As requested by EPA[20], this evaluation is completed as if DSI did not already exist." The details of the costs calculations are provided in Appendix A of this report.

The annual tons reduced used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable for the control technologies multiplied by the future annual heat input. The future annual heat input is based on the average actual heat input from CAMD for 2010 to 2014.

[19] The achievable emission rates in Table 5-2 are on an annual average basis.

[20] Letter from Guy Donaldson (EPA Region 6) to Bill Matthews (Cleco), March, 16, 2016. Re: Preliminary review of BART Determination.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. As documented later in the report, the additional cost of dry and wet scrubbing/FGD is not justified in light of the small amount of improvement in visibility impacts as compared to the high cost effectiveness values and exceptionally high incremental cost effectiveness values.

Energy Impacts and Non-Air Quality Impacts

As illustrated in Table 5-3 and in the following section, wet scrubbing is expected to achieve only slightly more visibility improvement as the proposed dry scrubbing technology. However, the negative non-air quality environmental impacts are greater with wet scrubbing systems. Wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be managed and/or treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. Wet scrubbing systems require increased power requirements and increased reagent usage over dry scrubbers. Thus, from an overall environmental perspective, dry scrubbing is superior to wet scrubbing.

Remaining Useful Life

The remaining useful life of Unit 2 does not impact the annualized capital costs for either semi-dry scrubbing or wet scrubbing because the useful life of the unit is anticipated to be at least as long as the control equipment capital cost recovery period, which is 20 years. Useful life varies with the equipment being evaluated. The EPA's *Control Cost Manual* includes the assumption that large control systems such as SCR systems and fabric filters have a useful life of 20 years. While the manual does not include a chapter on FGD systems, it is reasonable to assume that the DFGD and WFGD systems will have a similar useful life as the other large air pollution control systems. Additionally, a 20-year useful life has been used in other Regional Haze BART determinations for retrofit FGD systems. S&L recommends using a 20 year useful life for the cost effectiveness calculations. Despite this, the cost effectiveness calculations have been updated to reflect a 30 year useful life per EPA's request letter[21].

[21] Letter from Guy Donaldson (EPA Region 6) to Bill Matthews (Cleco), March, 16, 2016. Re: Preliminary review of BART Determination.

Table 5-3. Summary of Cost Effectiveness for Unit 2 [3]

Control Technology	Controlled Emission Level	Controlled Emission Rate	SO_2 Reduced	Total Annual Operating Costs above Baseline	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(lb/MMBtu)	(tpy)	(tpy)	($/yr)	($/yr)	($/ton)	($/ton)
Baseline	0.57	9,077	--	--	--		
Current: DSI + FF	0.41	6,529	2,548	$8,543,800	$19,239,300	$7,551	--
Enhanced DSI + FF	0.30	4,777	4,300	$10,239,100	$20,934,100	$4,869	$967
DFGD-SDA System[1]	0.06	955	8,122	$30,062,600	$69,755,500	$8,589	$12,774
WFGD System[2]	0.04	637	8,440	$23,015,200	$47,096,600	$5,580	$6,319

[1] Incremental cost for DFGD is compared to Enhanced DSI

[2] Incremental cost for WFGD is compared to Enhanced DSI, since DFGD is determined to be an inferior technology (higher annual cost).

[3] Based on cost evaluation prepared by Sargent & Lundy, April 8, 2016.

EVALUATION OF VISIBILITY IMPACT OF FEASIBLE CONTROLS FOR UNIT 2

An impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option on a 24-hour basis.[22]

Table 5-4 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[23,24,25] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[26]

Table 5-4. Summary of 24-hour Average Emission Rates Modeled to Reflect SO_2 Controls for Unit 2

Source	SO_2 (lb/hr)	SO_4[1] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Baseline[2]	5,415.00	0.00	3,298.63	89.57	69.01	2.65	28.37	189.60
DFGD (SDA)	570.00	0.00	3,298.63	58.04	55.89	73.52	2.15	189.60
WFGD	399.00	0.00	3,298.63	69.36	73.48	43.94	2.82	189.60
Existing DSI + FF	3,876.00	0.00	3,298.63	22.89	22.04	143.82	0.85	189.60
Enhanced DSI + FF	2,850.00	0.00	3,298.63	22.89	22.04	143.82	0.85	189.60

[1] SO_4 as it is displayed in this table represents ammonium sulfate.
[2] Baseline has been modified to reflect "uncontrolled" operation of Unit 2, per EPA Request Letter (3/16/16).

Comparisons of the existing visibility impacts and the visibility impacts based on wet scrubbing, semi-dry scrubbing, dry sorbent injection with fabric filter, and enhanced DSI with fabric filter for Unit 2 are provided in Table 5-5. These tables summarize the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for the Class I areas of interest.

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[22] The annual average emission rates, e.g., 0.06 lb/MMBtu for SDA, were converted to 24-hour maximum emission rates using a correlation factor developed by Sargent & Lundy based on a comparison of actual annual emission rates and their corresponding maximum hourly emission rates during 2010-2014.

[23] DFGD speciation is based on NPS workbook, "Dry Bottom Boiler burning Pulverized Coal using FGD+FF.xls", heating value of 8,757 btu/lb, 0.45% sulfur, 5.53% ash, and baseline PM_{10} emission rate of 189.6 lb/hr. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[24] WFGD speciation is based on NPS workbook, "Wet Bottom Boiler burning Pulverized Coal using FGD+ESP.xls". NPS: Ibid.

[25] DSI/Enhanced DSI speciation is based on NPS workbook, "Dry Bottom Boiler burning Pulverized Coal using FGD+FF.xls". NPS, Ibid . At the recommendation of Don Shepherd (NPS) via email (dated 10/13/15), the species calculation was modified to incorporate EPRI's F2 factor of 0.01, where 0.01 is the F2 factor for "Dry FGD and baghouse" obtained from EPRI Table 4-5.

[26] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 5-5. Summary of Modeled Visibility Impacts[1] from SO_2 Control for Unit 2 (2001-2003)

	Breton		Caney Creek	
	98% Impact (Δdv)	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Baseline	0.724	25	0.734	45
DSI + FF	0.590	20	0.649	34
Improvement over Baseline	*0.134*	*5*	*0.085*	*11*
Enhanced DSI + FF	0.498	13	0.612	25
Improvement over Baseline	*0.226*	*12*	*0.122*	*20*
Improvement over DSI + FF	*0.092*	*7*	*0.037*	*9*
DFGD-SDA System	0.288	2	0.423	12
Improvement over Baseline	*0.436*	*23*	*0.311*	*33*
Improvement over DSI + FF	*0.302*	*18*	*0.226*	*22*
Improvement over Enhanced DSI + FF	*0.210*	*11*	*0.189*	*13*
WFGD System	0.279	2	0.412	11
Improvement over Baseline	*0.445*	*23*	*0.322*	*34*
Improvement over DSI + FF	*0.311*	*18*	*0.237*	*23*
Improvement over Enhanced DSI + FF	*0.219*	*11*	*0.200*	*14*
Improvement over DFGD-SDA System	*0.009*	*0*	*0.011*	*1*

[1] The visibility impact and improvement values shown above have been calculated from values that include more decimal places than what are shown and therefore may be slightly different than actual model results.

As shown in Table 5-5, based on visibility predictions from the CALPUFF modeling system, for Breton, the operation of a an enhanced DSI achieving 0.30 lb/MMBtu will result in up to a 0.226 Δdv improvement over baseline visibility and up to a 0.092 Δdv improvement over the existing DSI + FF system. Furthermore, for the same Class I area (Breton), DFGD and WFGD will result in only 0.210 Δdv and 0.219 Δdv additional improvement over enhanced DSI.

For convenience, Table 5-6 provides a condensed summary of the predicted improvements to visibility impairment alongside the estimated control costs. Given that semi-dry and wet scrubbing requires a significantly higher capital investment and is more expensive from an incremental cost effectiveness standpoint than enhanced DSI, scrubbing cannot be justified as BART at Unit 2.

Table 5-6. Summary of Cost Effectiveness[4] and Class I Area Improvement for Unit 2

Control Description	SO_2 Emissions (lb/MMBtu)[3]	Emission Reduction from Baseline (tons/yr)	Total Capital Cost ($)	Total Annual Cost ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Class I Area	98th Percentile Δdv	Improvement over Baseline in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv[1,2]	Average Cost Effectiveness $/Δdv
Baseline	0.57	--	--	--			Breton	0.724	-	-	-
							Caney Creek	0.734	-	-	-
DSI + FF	0.41	2,548	$132,720,370	$19,239,300	$7,551		Breton	0.590	0.134	-	-
							Caney Creek	0.649	0.085	-	-
Enhanced DSI + FF	0.30	4,300	$132,720,370	$20,934,100	$4,869	$967	Breton	0.498	0.226	0.092	92,628,761
							Caney Creek	0.612	0.122	0.037	171,590,984
DFGD-SDA System[1]	0.06	8,122	$492,551,139	$69,755,500	$8,589	$12,774	Breton	0.288	0.436	0.210	159,989,679
							Caney Creek	0.423	0.311	0.189	224,294,212
WFGD System[2]	0.04	8,440	$298,827,500	$47,096,600	$5,580	$6,319	Breton	0.279	0.445	0.219	105,835,056
							Caney Creek	0.412	0.322	0.200	146,262,733

[1] Incremental cost for DFGD is compared to Enhanced DSI.

[2] Incremental cost for WFGD is compared to Enhanced DSI, since DFGD is determined to be an inferior technology (higher annual cost).

[3] Annual average.

[4] Based on cost evaluation prepared by Sargent & Lundy, April 8, 2016.

PROPOSED BART FOR SO_2 FOR UNIT 2

Cleco is proposing that the SO_2 BART emission level for Unit 2 be 0.30 lb/MMBtu based on the operation of enhanced DSI with fabric filter. Cleco is proposing to meet this limit on an annual average basis. Compliance will be demonstrated using data from the existing CEMS.

6. NO_X BART EVALUATION

On June 7, 2012 EPA published a final rule allowing states participating in the Cross-State Air Pollution Rule (CSAPR) trading program to use CSAPR to satisfy BART. Additionally, EPA states in its Section 114 response letter to Cleco that:

> *Based on the current status of CSAPR, Cleco's facilities currently have BART coverage for NO_X emissions and a review of NO_X controls is not necessary."*[27]

Cleco is proposing to satisfy BART for NO_x by complying with CSAPR at Brame Unit 1 and Unit 2.

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[27] Donaldson, Guy. Cleco's Questions/Comments Regarding Section 114(a) Information Request letter to Bill Matthews (Cleco), June 9, 2015.

7. PM_{10} BART EVALUATION

For Unit 1, Cleco proposes a BART determination of fuel switch to natural gas only. The potential to emit under this scenario is 37.3 lb/hr.[28]

EPA approved BART determinations in Arkansas for an ESP currently installed on a coal unit as BART for PM_{10}.[29] Since Unit 2 is currently equipped with ESP for control of PM_{10}, Cleco proposes to use this determination to satisfy BART for PM_{10}. Moreover, Unit 2 is also equipped with a fabric filter downstream of the existing DSI system; this fabric filter more than satisfies BART. The potential to emit of PM for Unit 2 is 545 lb/hr.

[28] Based on the total PM emission factor, 0.00745 lb/MMBtu, from AP-42 Section 1.4 (7/98) and the unit's maximum heat input capacity, 5,004 MMBtu/hr.

[29] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

APPENDIX A: SO_2 CONTROL COST CALCULATIONS FOR UNIT 2

Prepared by Sargent & Lundy

BART Cost Evaluation
SO2 Control

RODEMACHER UNIT 2
SO2 CONTROL SUMMARY

Pollutant:	SO2	Unit	Notes
Annual Average Heat Input (2010-2014)	31,848,421	mmBtu/yr	Annual average heat input calculated over a five year operating period (2010-2014).
Average Capcity Factor	64%	%	Based on average heat input and maximum heat input identified between 2010-2014. (Removed 13 week outage between 3/10/2014 and 6/2/2014).

Control Technology	Expected Emission Rate (lb/MMBtu)	Expected Emissions (ton/year)	Expected Emissions Reduction (ton/year)	Notes
Baseline Emissions	**0.57**	**9,077**	0	Based on the average emission rate over a five year operating period (2010-2014).
Alternative 1: Current DSI + FF	**0.41**	6,529	2,548	
Alternative 2: Enhanced DSI + FF	**0.30**	4,777	4,300	
Alternative 3: DFGD-SDA System[1]	**0.06**	955	8,122	
Alternative 4: WFGD System[2]	**0.04**	637	8,440	

Notes:
[1] Based on directive from Cleco personnel, 0.06 lb/MMBtu will be used as part of the cost effectiveness analysis for this BART evaluation; however, this value should not be used by the state of Louisiana as an enforceable SO2 permit limit, as this is not predicted to be consistently achievable over the life of the equipment or with varying operating conditions.
[2]Based on directive from Cleco personnel, 0.04 lb/MMBtu will be used as part of the cost effectiveness analysis for this BART evaluation; however, this value should not be used by the state of Louisiana as an enforceable SO2 permit limit, as this is not predicted to be consistently achievable over the life of the equipment or with varying operating conditions.

Control Technology	Emissions (tpy)	Tons of SO2 Removed from Baseline (tpy)	Total Capital Requirement ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs above Baseline ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline Emissions	9,077	--	--	--	--	--		
Alternative 1: Current DSI + FF	6,529	2,548	$132,720,370	$10,695,500	$8,543,800	$19,239,300	**$7,551**	
Alternative 2: Enhanced DSI + FF	4,777	4,300	$132,720,370	$10,695,000	$10,239,100	$20,934,100	**$4,869**	$967
Alternative 3: DFGD-SDA System[1,3]	955	8,122	$492,551,139	$39,692,900	$30,062,600	$69,755,500	**$8,589**	$12,774
Alternative 4: WFGD System[2,3]	637	8,440	$298,827,500	$24,081,400	$23,015,200	$47,096,600	**$5,580**	$6,319

Notes:
[1] Incremental cost for DFGD is compared to Enhanced DSI
[2] Incremental cost for WFGD is compared to Enhanced DSI, since DFGD is determined to be an inferior technology (higher annual cost).
[3] Salvage value is a very market dependent item. Scrap value of appropriate items such as structural steel, cables, and copper can be provided however the total value is very minimal. The cost of processing salvageable materials would be higher than the value of the material itself, and therefore there would be at most a trivial financial benefit to attempting to sell the materials. As such, this cost has not been included.

BART Cost Evaluation
Dry Sorbent Injection (DSI) + Polishing Fabric Filter (FF)

RODEMACHER UNIT 2
BART COST EVALUATION - CURRENT DSI WORKSHEET

	INPUT
Case	**1 x 552 MW-gross PC Boiler**
Annual Average Heat Input (mmBtu/yr)	**31,848,421**
Baseline SO2 Emission Rate w/ DSI (lb/mmBtu)	**0.57**
Post DSI SO2 Emission Rate (lb/mmBtu)	**0.41**
Capacity Factor used of Cost Estimates (%)	**64%**

CAPITAL COSTS	**Rodemacher Unit 2**	
Direct Costs		
Indirect Costs		
Contingency		
Total Plant Cost		
Lost Production		
Escalation		
Allow. for Funds During Constr. (AFUDC)		
Total Capital Investment (TCI)	**$132,720,370**	Total Capital Investment is based on actual expenditures made by Cleco for the DSI retrofit.
Total Capital Investment ($/kW - gross)	$240	
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0806	n = 30 years; i = 7% (pretax marginal rate of return)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$10,695,500**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Trona Reagent Cost	$1,005,740	Based on average heat input, SO2 removal rate, 1,500 lb/hr Trona, $240/ton for trona.
Waste Disposal Cost	$12,000	Based on average heat input, SO2 removal rate and $3/ton on-site disposal cost. Disposal cost only includes DSI by-products and does not include fly ash collected in HESP. No credit is assumed for by-product sales.
Bag and Cage Replacement Cost	$659,000	Based on $90/bag and $26/cage. Bags replaced every 3 years, cages every 6 years.
Auxiliary Power Cost	$832,000	Based on auxiliary power requirement at $32/MWh.
Total Variable O&M Costs	$2,508,740	
Fixed O&M Costs		
Additional Operators per shift	0.5	Based on S&L O&M estimate for DSI.
Operating Labor	$216,800	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$32,500	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$238,500	100% of maintenance labor. EPA Control Cost Manual, page 2-32
Maintenance Labor	$238,500	110% of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$726,300	
Indirect Operating Cost		
Property Taxes	$1,327,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,327,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,654,400	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,308,800	
Total Annual Operating Cost	**$8,543,800**	
TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$10,695,500**	
Annual Operating Cost	**$8,543,800**	
Total Annual Cost	**$19,239,300**	

BART Cost Evaluation
Enhanced Dry Sorbent Injection (DSI) + Polishing Fabric Filter (FF)

RODEMACHER UNIT 2
BART COST EVALUATION - ENHANCED DSI WORKSHEET

	INPUT
	1 x 552 MW-gross
Case	**PC Boiler**
Annual Average Heat Input (mmBtu/yr)	**31,848,421**
Baseline SO2 Emission Rate (lb/mmBtu)	**0.57**
Post Enhanced DSI SO2 Emission Rate (lb/mmBtu)	**0.30**
Capacity Factor used of Cost Estimates (%)	**64%**

CAPITAL COSTS	Rodemacher Unit 2	
Direct Costs		
Indirect Costs		
Contingency		
Total Plant Cost		
Lost Production		
Escalation		
Allow. for Funds During Constr. (AFUDC)		
Total Capital Investment (TCI)	**$132,720,370**	Total Capital Investment is based on actual expenditures made by Cleco for the DSI retrofit.
Total Capital Investment ($/kW - gross)	$240	
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0806	n = 30 years; i = 7% (pretax marginal rate of return)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$10,695,000**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Trona Reagent Cost	$2,681,972	Based on average heat input, SO2 removal rate, 4,000 lb/hr Trona, $240/ton for trona.
Waste Disposal Cost	$31,000	Based on average heat input, SO2 removal rate and $3/ton on-site disposal cost. Disposal cost only includes DSI by-products and does not include fly ash collected in HESP. No credit is assumed for by-product sales.
Bag and Cage Replacement Cost	$659,000	Based on $90/bag and $26/cage. Bags replaced every 3 years, cages every 6 years.
Auxiliary Power Cost	$832,000	Based on auxiliary power requirement at $32/MWh.
Total Variable O&M Costs	$4,203,972	
Fixed O&M Costs		
Additional Operators per shift	0.5	Based on S&L O&M estimate for DSI.
Operating Labor	$216,800	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$32,500	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$238,500	100% of maintenance labor. EPA Control Cost Manual, page 2-32
Maintenance Labor	$238,500	110% of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$726,300	
Indirect Operating Cost		
Property Taxes	$1,327,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,327,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,654,400	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,308,800	
Total Annual Operating Cost	**$10,239,100**	
TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$10,695,000**	
Annual Operating Cost	**$10,239,100**	
Total Annual Cost	**$20,934,100**	

BART Cost Evaluation
Dry Flue Gas Desulfurization

RODEMACHER UNIT 2
BART COST EVALUATION - DRY FGD WORKSHEET

	INPUT	
Case	**1 x 552 MW-gross PC Boiler**	
Annual Average Heat Input (mmBtu/yr)	**31,848,421**	
Baseline SO2 Emission Rate (lb/mmBtu)	**0.57**	
Post Dry FGD SO2 Emission Rate (lb/mmBtu)	**0.060**	* Based on directive from Cleco personnel, 0.06 lb/MMBtu will be used as part of the cost effectiveness analysis for this BART evaluation; however, this value should not be used by the state of Louisiana as an enforceable SO2 permit limit, as this is not predicted to be consistently achievable over the life of the equipment or with varying operating conditions.
Capacity Factor used of Cost Estimates (%)	**64%**	

CAPITAL COSTS	Rodemacher Unit 2	
Direct Costs	$294,345,200	Equipment capital costs were based on Sargent & Lundy's conceptual cost estimating system, using Rodemacher specific fuel specifications, boiler configuration and site-specific constraints. Direct costs inlcude equipment (absorbers, reagent prep and recycle systems, chimney, waste ash handling modifications, FF modificaitons, ductwork, electrical mods, piping etc..), material, installation and direct project costs (e.g., scaffolding, overtime labor, per diem, freight, contractor G&A expense, contractor profit, consumables). Actual costs for fabric filter and BOP work completed for MATS also inlcuded.
Indirect Costs	$39,628,900	Indirect costs include engineering, construction management support, and contractor profit. Owner's cost removed.
Contingency	$44,343,900	20% of Direct and Indirect Project Cost of new equipment only (contingency for costs for fabric filter and BOP work completed for MATS not inlcuded).
Total Plant Cost	$492,551,139	Sum of Direct Cost, Indirect Cost and Contingency.
Lost Production	$0	New DFGD system built off to the side while unit is operating, and tied-in during planned major outage.
Escalation	$0	Not included.
Allow. for Funds During Constr. (AFUDC)	$0	AFUDC removed.
Total Capital Investment (TCI)	**$492,551,139**	Sum of Direct Costs, Indirect Costs, Contingency, Lost Production, AFUDC and Escalation.
Total Capital Investment ($/kW - gross)	$892	
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0806	n = 30 years; i = 7% (pretax marginal rate of return)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$39,692,900**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Lime Reagent Cost	$1,413,623	Based on average heat input, SO2 removal rate, 1.5 stoichiometry, 90% CaO, $110/ton for lime.
Water Cost	$392,238	Based on $1.50/1000 gal.
Waste Disposal Cost	$77,000	Based on average heat input, SO2 removal rate and $3/ton on-site disposal cost. Disposal cost only includes DFGD by-products and does not include fly ash collected in HESP. No credit is assumed for by-product sales.
Bag and Cage Replacement Cost	$879,000	Based on $90/bag and $26/cage. Bags replaced every 3 years, cages every 6 years.
Auxiliary Power Cost	$1,788,000	Based on auxiliary power requirement at $32/MWh.
Total Variable O&M Costs	$4,549,861	
Fixed O&M Costs		
Additional Operators per shift	4.0	Based on S&L O&M estimate for dry FGD.
Operating Labor	$1,734,500	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$260,200	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$1,908,000	100% of maintenance labor. EPA Control Cost Manual, page 2-32
Maintenance Labor	$1,908,000	110% of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$5,810,700	
Indirect Operating Cost		
Property Taxes	$4,925,500	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$4,925,500	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$9,851,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$19,702,000	
Total Annual Operating Cost	**$30,062,600**	
TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$39,692,900**	
Annual Operating Cost	**$30,062,600**	
Total Annual Cost	**$69,755,500**	

BART Cost Evaluation
Wet Flue Gas Desulfurization

RODEMACHER UNIT 2
BART COST EVALUATION - WET FGD WORKSHEET

	INPUT	
	1 x 552 MW-gross	
Case	PC Boiler	
Annual Average Heat Input (mmBtu/yr)	31,848,421	
Baseline SO2 Emission Rate (lb/mmBtu)	0.57	
Post Wet FGD SO2 Emission Rate (lb/mmBtu)*	0.040	*Based on directive from Cleco personnel, 0.04 lb/MMBtu will be used as part of the cost effectiveness analysis for this BART evaluation; however, this value should not be used by the state of Louisiana as an enforceable SO2 permit limit, as this is not predicted to be consistently achievable over the life of the equipment or with varying operating conditions.
Capacity Factor used of Cost Estimates (%)	64%	

CAPITAL COSTS	**Rodemacher Unit 2**	
Direct Costs	$222,166,500	Equipment capital costs were based on Sargent & Lundy's conceptual cost estimating system, using Rodemacher specific fuel specifications, boiler configuration and site-specific constraints. Direct costs inlcude equipment (absorber, reagent prep and dewatering systems, chimney, ductwork, electrical mods, piping etc..), material, installation and direct project costs (e.g., scaffolding, overtime labor, per diem, freight, contractor G&A expense, contractor profit, consumables).
Indirect Costs	$26,856,400	Indirect costs include engineering, construction management support, and contractor profit. Owner's cost removed.
Contingency	$49,804,600	20% of Direct and Indirect Project Costs (Future Retrofits Only)
Total Plant Cost	$298,827,500	Sum of Direct Cost, Indirect Cost and Contingency.
Lost Production	$0	New WFGD system built off to the side while unit is operating, and tied-in during planned major outage.
Escalation	$0	Not included.
Allow. for Funds During Constr. (AFUDC)	$0	AFUDC removed.
Total Capital Investment (TCI)	**$298,827,500**	Sum of Direct Costs, Indirect Costs, Contingency, Lost Production, AFUDC and Escalation.
Total Capital Investment ($/kW - gross)	$541	
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0806	n = 30 years; i = 7% (pretax marginal rate of return)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$24,081,400**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Limestone Reagent Cost	$603,444	Based on average heat input, SO2 removal rate, 1.1 stoichiometry, 95% CaCO3, and $40/ton for limestone.
Water Cost	$482,755	Based on 1.50/1000 gal.
Waste Disposal Cost	$91,000	Based on average heat input, SO2 removal rate and $3/ton on-site disposal cost. Disposal cost only includes WFGD by-products and does not include fly ash collected in HESP. No credit is assumed for by-product sales.
Auxiliary Power Cost	$1,169,000	Based on auxiliary power requirement at $32/MWh.
Total Variable O&M Costs	$2,346,199	
Fixed O&M Costs		
Additional Operators per shift	6.0	Based on S&L O&M estimate for wet FGD.
Operating Labor	$2,601,700	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$390,300	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$2,861,900	100% of maintenance labor. EPA Control Cost Manual, page 2-32
Maintenance Labor	$2,861,900	110% of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$8,715,800	
Indirect Operating Cost		
Property Taxes	$2,988,300	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,988,300	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$5,976,600	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$11,953,200	
Total Annual Operating Cost	**$23,015,200**	
TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$24,081,400**	
Annual Operating Cost	**$23,015,200**	
Total Annual Cost	**$47,096,600**	

Rodemacher 2 MATS Summary as of 7/31/15
100% $

Vendor/Item	*Budget*	**S&L Notes to Adjustments**
ADA Carbon Solutions - activated carbon		Delete carbon contract
Aerofin	784,804	
Babcock & Wilcox Company - CEMS		Delete
Casey	49,707,634	2.5M for ACI silo, 3.6M for DSI. Assume labor is 60% of equipment price so delete $3.66M from Casey contract for labor.
Hamon Research-Cottrell	30,855,820	Subtracted HRC ACI/DSI contract of $8.25M
Howden	7,523,296	
MS&W - Builder's Risk Policy	164,953	80% of total cost (20% of equipment based on DSI/ACI)
Rexel Electrical & Datacom	2,029,979	80% of total cost (20% of equipment based on DSI/ACI)
Sargent & Lundy	4,402,782	80% of total cost (20% of equipment based on DSI/ACI)
Natronx - Trona		Delete Trona contract
United Conveyor Service Corp.		Delete DSI system
Zachry Construction	1,075,348	80% of total cost (20% of equipment based on DSI/ACI)
Miscellaneous	11,541,082	80% of total cost (20% of equipment based on DSI/ACI)
Cleco Miscellaneous (T01, F01, etc)	200,000	80% of total cost (20% of equipment based on DSI/ACI)
Payroll	2,768,610	80% of total cost (20% of equipment based on DSI/ACI)
A&G Loadings	1,200,000	80% of total cost (20% of equipment based on DSI/ACI)
Contingency	(745,442)	Not included
Subtotals	111,508,866	
AFUDC	2,724,273	Not Included.
Grand Totals (includes accruals)	114,233,139	

CLECO
RODEMACHER UNIT 2
DRY FGD ADDITION

Estimator	GA
Labor rate table	15LAALX
Project No.	11634-103
Estimate Date	4/4/2016
Reviewed By	AK
Approved By	MNO
Estimate No.	33551B
Estimate Class	Conceptual
Cost index	LAALX

Estimate No.: 33551B
Project No.: 11634-103
Estimate Date: 4/4/2016
Prep./Rev/App.: GA/AK/MNO

CLECO
RODEMACHER UNIT 2
DRY FGD ADDITION

Sargent & Lundy

Group	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
11.00.00	DEMOLITION	700,000		18,000	8,537	847,065	1,565,065
21.00.00	CIVIL WORK	360,000		219,790	3,513	268,948	848,738
22.00.00	CONCRETE			1,718,284	27,995	1,662,251	3,380,535
23.00.00	STEEL			10,755,660	146,145	14,675,904	25,431,564
24.00.00	ARCHITECTURAL	1,276,000		606,730	3,969	317,408	2,200,138
25.00.00	CONCRETE CHIMNEY & STACK	9,633,000					9,633,000
27.00.00	PAINTING & COATING	150,000					150,000
31.00.00	MECHANICAL EQUIPMENT	1,000,000	43,549,700	79,000	257,825	26,006,060	70,634,760
33.00.00	MATERIAL HANDLING EQUIPMENT		4,400,000		28,119	1,838,352	6,238,352
34.00.00	HVAC			88,500	436	30,264	118,764
35.00.00	PIPING			673,829	23,458	1,832,085	2,505,914
36.00.00	INSULATION			1,192,302	45,020	2,491,883	3,684,185
41.00.00	ELECTRICAL EQUIPMENT	70,000	9,397,500	1,794,013	40,801	2,709,315	13,970,828
42.00.00	RACEWAY, CABLE TRAY & CONDUIT			2,125,378	95,221	5,004,826	7,130,204
43.00.00	CABLE			1,748,143	16,331	1,164,576	2,912,719
44.00.00	CONTROL & INSTRUMENTATION	265,000	3,435,000	57,500	14,081	982,310	4,739,810
51.00.00	SUBSTATION, SWITCHYARD & TRANSMISSION LINE		291,000	664,970	2,611	184,337	1,140,307
	TOTAL DIRECT	13,454,000	61,073,200	21,742,098	714,062	60,015,585	156,284,883

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	60,015,585		714,062
Material	21,742,098		
Subcontract	13,454,000		
Process Equipment	61,073,200		
	156,284,883	156,284,883	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	6,540,600		
91-2 Cost Due To OT 5-10's	7,567,200		
91-3 Cost Due To OT 6-10's	2,425,300		
91-4 Per Diem	7,140,600		
91-5 Consumables	817,617		
91-6 Freight on Material	1,087,100		
91-7 Freight on Process Equip			
91-8 Sales Tax			
91-9 Contractors G&A	10,624,900		
91-10 Contractors Profit	5,312,400		
	41,515,717	197,800,600	
Indirect Costs:			
93-1 Engineering Services	15,824,000		
93-2 CM Support	5,934,000		
93-3 Start-Up/Commissioning	1,978,000		
93-4 Start-Up/Spare Parts	183,200		
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	23,919,200	221,719,800	
Contingency:			
94-1 Contingency on Material	5,218,100		
94-2 Contingency on Labor	19,436,600		
94-3 Contingency on Sub.	2,690,800		
94-4 Contingency on Process Eq	12,214,600		
94-5 Contingency on Indirect	4,783,800		
	44,343,900	266,063,700	
Escalation:			
96-1 Escalation on Material			
96-2 Escalation on Labor			
96-3 Escalation on Subcontract			
96-4 Escalation on Process Eq			
96-5 Escalation on Indirects			
		266,063,700	
98 Interest During Constr			
		266,063,700	
Total		***266,063,700***	

CLECO
RODEMACHER UNIT 2
WET FGD ADDITION

Estimator	M. N. OZAN
Labor rate table	15LAALX
Project No.	11634-103
Estimate Date	4/4/2016
Reviewed By	AK
Approved By	MNO
Estimate No.	33552B
Estimate Class	Conceptual
Cost index	LAALX

CLECO
RODEMACHER UNIT 2
WET FGD ADDITION

Sargent & Lundy

Group	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
11.00.00	DEMOLITION				2,200	218,614	218,614
21.00.00	CIVIL WORK			202,277	8,436	782,170	984,447
22.00.00	CONCRETE			2,410,222	47,912	2,965,925	5,376,146
23.00.00	STEEL			8,608,108	97,837	9,886,539	18,494,647
24.00.00	ARCHITECTURAL			9,076,000	66,678	6,633,581	15,709,581
25.00.00	CONCRETE CHIMNEY & STACK	12,900,000			0		12,900,000
27.00.00	PAINTING & COATING			6,000	660	37,076	43,076
31.00.00	MECHANICAL EQUIPMENT	980,000	40,288,500	267,990	258,922	26,089,403	67,625,893
33.00.00	MATERIAL HANDLING EQUIPMENT	100,000	8,515,700	74,750	28,801	1,901,646	10,592,096
34.00.00	HVAC		1,234,000		21,342	1,397,910	2,631,910
35.00.00	PIPING			4,467,470	100,715	7,865,856	12,333,326
36.00.00	INSULATION			1,252,155	28,092	1,554,915	2,807,070
41.00.00	ELECTRICAL EQUIPMENT		9,017,500	1,584,835	21,612	1,293,929	11,896,264
42.00.00	RACEWAY, CABLE TRAY & CONDUIT	3,600		2,402,783	103,442	5,436,916	7,843,299
43.00.00	CABLE			3,205,659	32,902	2,346,276	5,551,935
44.00.00	CONTROL & INSTRUMENTATION	340,000	3,005,000	490,000	10,825	755,222	4,590,222
51.00.00	SUBSTATION, SWITCHYARD & TRANSMISSION LINE		291,000	664,970	2,611	184,337	1,140,307
	TOTAL DIRECT	14,323,600	62,351,700	34,713,218	832,988	69,350,315	180,738,833

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Estimate Totals

Description	Amount	Cuts/Adds	Net Amount	Totals	Hours
Direct Costs:					
Labor			69,350,500		832,986
Material			34,713,300		
Subcontract			14,323,600		
Process Equipment			62,351,700		
			180,739,100	180,739,100	
Other Direct & Construction Indirect Costs:					
91-1 Scaffolding	5,548,000				
91-2 Cost Due To OT 5-10's	8,771,500				
91-3 Cost Due To OT 7-10's	2,810,400				
91-4 Per Diem					
91-5 Consumables	693,500				
91-6 Freight on Material	1,735,700				
91-7 Freight on Process Equip	3,117,600				
91-8 Sales Tax					
91-9 Contractors G&A	12,500,500				
91-10 Contractors Profit	6,250,200				
	41,427,400			222,166,500	
Indirect Costs:					
93-1 Engineering Services	17,773,300				
93-2 CM Support	6,665,000				
93-3 Start-Up/Commissioning	2,221,700				
93-4 Start-Up/Spare Parts	196,400				
93-5 Excess Liability Insur.					
93-6 Sales Tax On Indirects					
93-7 Owners Cost					
93-8 EPC Fee					
	26,856,400			249,022,900	
Contingency:					
94-1 Contingency on Material	8,424,700				
94-2 Contingency on Labor	20,050,000				
94-3 Contingency on Sub.	2,864,700				
94-4 Contingency on Process Eq	13,093,900				
94-5 Contingency on Indirect	5,371,300				
	49,804,600			298,827,500	
Escalation:					
96-1 Escalation on Material					
96-2 Escalation on Labor					
96-3 Escalation on Subcontract					
96-4 Escalation on Process Eq					
96-5 Escalation on Indirects					
				298,827,500	
98 Interest During Constr					
				298,827,500	
Total				***298,827,500***	

April 8, 2016

Please provide documentation for the 20% contingency factor used in the scrubber cost analyses.

AACE categorizes cost estimates by the "degree of project definition."[1] The discrete levels of project definition used by AACE for classifying cost estimates correspond to the typical phases of project evaluation, authorization, and execution used during a project life cycle, and are summarized in the following table:

Table 1
Cost Estimate Classification Matrix for the Process Industries (AACE 18R-97) [2]

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [Note 1]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Note 1: The +/- accuracy values provided by AACE in the table represent typical percentage variation of actual project costs from the cost estimate after application of contingency at a 50% level of confidence for a given project scope. AACE does not assign a specific contingency factor to each cost estimate class, but assumes that contingency has been applied to all classes. The state of process technology, availability of applicable reference cost data, and other project risks affect the accuracy range.

As noted in AACE 18R-97, the maturity level of project definition deliverables is the primary determining characteristic of the cost estimating class.[3] The maturity level of project definition is indicated by a percent of complete project definition and percent complete of engineering deliverables. The following table, taken from AACE 18R-97,[4] maps the extent and maturity of cost estimate input information (i.e., deliverables) for each of the five AACE cost estimate classes.

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[1] AACE International Recommended Practice No. 17R-97 *Cost Estimate Classification System*, pg. 2, included as Attachment 7.

[2] AACE International Recommended Practice No. 18R-97 *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*, pg. 2, included as Attachment 8.

[3] *Id.*.

[4] *Id.*, at 9.

Table 2
Estimate Input Checklist and Maturity Matrix (Primary Classification Determinate)*

	ESTIMATE CLASSIFICATION				
	CLASS 5	CLASS 4	CLASS 3	CLASS 2	CLASS 1
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
General Project Data:					
Project Scope Description	General	Preliminary	Defined	Defined	Defined
Plant Production/Facility Capacity	Assumed	Preliminary	Defined	Defined	Defined
Plant Location	General	Approximate	Specific	Specific	Specific
Soils & Hydrology	None	Preliminary	Defined	Defined	Defined
Integrated Project Plan	None	Preliminary	Defined	Defined	Defined
Project Master Schedule	None	Preliminary	Defined	Defined	Defined
Escalation Strategy	None	Preliminary	Defined	Defined	Defined
Work Breakdown Structure	None	Preliminary	Defined	Defined	Defined
Project Code of Accounts	None	Preliminary	Defined	Defined	Defined
Contracting Strategy	Assumed	Assumed	Preliminary	Defined	Defined
Engineering Deliverables:					
Block Flow Diagrams	S/P	P/C	C	C	C
Plot Plans		S/P	C	C	C
Process Flow Diagrams (PFDs)		P	C	C	C
Utility Flow Diagrams (UFDs)		S/P	C	C	C
Piping & Instrument Diagrams (P&IDs)		S/P	C	C	C
Heat & Material Balances		S/P	C	C	C
Process Equipment List		S/P	C	C	C
Utility Equipment List		S/P	C	C	C
Electrical One-Line Drawings		S/P	C	C	C
Specifications & Datasheets		S	P/C	C	C
General Equipment Arrangement Drawings		S	C	C	C
Spare Parts Listings			P	P	C
Mechanical Discipline Drawings			S/P	P/C	C
Electrical Discipline Drawings			S/P	P/C	C
Instrumentation/Control System Discipline Drawings			S/P	P/C	C
Civil/Structural/Site Discipline Drawings			S/P	P/C	C

* The maturity level for each defining deliverable is an approximation of the completion status of the deliverable, categorized in the table as: none (blank), started ("S"), preliminary ("P"), or complete ("C").

As shown in the table, Class 5 cost estimates require 0% to 2% maturity level of project definition deliverables, with general project scope description and preliminary block flow diagrams. Class 4 cost estimates require 1% to 15% maturity level of project definition deliverables, with preliminary project data, process flow diagrams, and other engineering deliverables. The S&L Cost Estimates were developed based on conceptual layouts of the Cleco FGD control systems and site-specific, but preliminary, engineering calculations. As such, based on the level of project definition, the S&L Cost Estimate would be characterized in between an AACE Class 4 and Class 5 cost estimate.

According to AACE 16R-90, "[p]roject contingency is included to cover the costs that would result if a detailed-type costing was followed as in a definitive-type study."[5] AACE defines a "Definitive Estimate" as "an estimate prepared from very defined engineering data. For construction, the engineering data includes as a minimum, nearly complete plot plans and elevations, piping and instrument diagrams, one line electrical diagrams, equipment data sheets and quotations, structural sketches, soil data and sketches of major foundations, building sketches and a complete set of specifications."[6] None of this detailed engineering work has been done for the Cleco FGD cost estimates. Although detailed, S&L's cost estimates were based on conceptual control system layouts and preliminary engineering calculations. Based on the level of project definition, engineering, and detail design completed for the control systems, the S&L Cost Estimate would be characterized in between an AACE Class 5 and Class 4 cost estimate. S&L's cost estimate is not a "definitive type study." As such, a project contingency must be included based on the level of engineering completed for the Cleco FGD cost estimates.

AACE provides expected accuracy ranges for each cost estimate class, but does not provide contingency levels for each class. However, AACE assumes that contingency has been applied to all classes (see, Table 1, note 1), and AACE 16R-90 states that project contingency ranges from 15% to 30% for a budget-type estimate. The Electric Power Research Institute ("EPRI") provides a similar cost estimate classification system that includes project contingency for each cost estimate class. Similar to AACE, EPRI defines "project contingency" as a capital cost factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at an actual site. The following table presents guidelines that relate project contingency to the level of design-estimating effort.[7]

[5] AACE International Recommended Practice No. 16R-90 *Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries*, pg. 15, included as Attachment 9.

[6] AACE International Examinee Format of Definitions, pg. 9, included as Attachment 10.

[7] Electric Power Research Institute. 1993. *Technical Assessment Guide* (TAG™) EPRI TR-102276s Vol. 1 Rev 7, page 5-5, included as Attachment 11.

Table 3
EPRI Design and Cost Estimate Classification

Item	Design-Estimate Effort	Project Contingency Range[a] (%)	Design Information Required	Cost Estimate Basis: Major Equipment	Cost Estimate Basis: Other Materials	Cost Estimate Basis: Labor
Class I	Simplified	30–50	General site conditions, geographic location & plant layout Process flow/ operation diagram Product output capacities	By overall project or section-by-section based on capacity/cost graphs, ratio methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II	Preliminary	15–30	As for Type Class I plus engineering specifics, e.g. : Major equipment specifications Preliminary P&I[b] flow diagrams	Recent purchase costs (including freight) adjusted to current cost index	By ratio to major equipment costs on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected average labor rates
Class III	Detailed	10–20	A complete process design Engineering design usually 20–40% complete Project construction schedule Contractual conditions and local labor conditions	Firm quotations adjusted for possible price escalation with some critical items committed	Firm unit cost quotes (or current billing costs) based on detailed quantity take-off	Estimated man-hour units (including assessment) using expected labor rate for each job classification
				Pertinent taxes & freight included		
Class IV	Finalized	5–10	As for Class III, with engineering essentially complete	As for Class III, with most items committed	As for Class III, with material on approximately 100% firm basis	As for Class III, some actual field labor productivity may be available

(a) Expressed as a percentage of the total of process capital, engineering and home office fees, and process contingency.
(b) P&I = Piping & Instrumentation.

Based on the level of engineering and design-estimating completed for the Cleco FGD control systems, the S&L Cost Estimate would be classified as in between a Class I or II design-estimate effort. EPRI provides a project contingency of 30 to 50% of the total process capital, engineering and home office fees, and process contingency for a Class I design-estimate effort and 15 to 30% for a Class II design-estimate effort. S&L used the less stringent contingency range since we have defined more than a Class I but not as much as a Class II. As such, S&L used a 20% project contingency factor, which is at the lower end of the range provided by EPRI and AACE.

APPENDIX B: POST-CONTROL PM SPECIATION CALCULATIONS FOR UNIT 2

Note: Calculations for baseline emissions were provided in the August 31, 2015 Screening Analysis Report.

Cleco, Rodemacher II (Unit 2)

Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

assumes heating value of 8757 Btu/lb and a sulfur content of 0.45 % and an ash content of 5.53 % and a heat input of 6534 mmBtu/hr and f(RH) = 1

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
PC-DB	0.0321	0.0171	0.0095	0.6	0.0076	0.0073	1	0.0003	10	**0.015**	**0.012**	SO4	3*f(RH)	**0.003**	SOA	4

Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
PC-DB	0.561	**0.299**	0.166	0.6	**0.133**	0.128	1	0.005	10	0.263	0.210	SO4	3*f(RH)	0.053	SOA	4

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions															
PC-DB	100%	53.2%	29.6%	0.6	23.6%	22.8%	1	0.9%	10	46.8%	37.4%	SO4	3*f(RH)	9.4%	SOA	4

If you are given Total PM10 emissions in lb/hr:

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions (**Bold** Value is Input by user.)															
PC-DB	189.6	100.9	56.0	0.6	44.8	43.2	1	1.7	10	88.7	71.0	SO4	3	17.7	SOA	4
		Weighted Extinction		*33.6*			*43.2*		*16.6*				*213.0*			*71.0*

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR	0.00 lb/hr	(SO_4)

Redistribute remainder of total PM_{10}:		189.6 lb/hr	
Coarse	47.2%	89.57 lb/hr	(PMC)
Fine Soil	36.4%	69.01 lb/hr	(PMF)
Fine EC	1.4%	2.65 lb/hr	(EC)
CPM OR	15.0%	28.37 lb/hr	(SOA)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012 — **Page Reference**

TSAR = Total sulfuric acid (H_2SO_4) release, lbs/yr — 4-11 (Eqn 4-10)

$= \{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$

= -169,978.53 lb/year

where:

EM_{Comb} = H_2SO_4 manufactured from combustion, lbs/yr — 4-1 (Eqn 4-1)

= K * F1 * E2

= 138,029.90 lb/year

where K = Units conversion factor

= 3063 lb H_2SO_4/ton SO_2

F1 = Fuel Impact Factor (PRB coal, all boiler types) — 4-6 (Table 4-1)

= 0.0019 *unitless*

E2 = SO_2 emission rate, tons/yr

= 23,717.70 tons/yr (max. day during '12-'14)

Cleco, Rodemacher II (Unit 2)

Refined Baseline

EPRI (Continued)

EM_{SCR}	=	H_2SO_4 manufactured from SCR	4-7 (Eqn 4-6)
	=	0 lb/year	SCR is not present
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	4-9 (Eqn 4-7)
	=	$EM_{FGC\_beforeAPH}$ $EM_{FGC\_afterAPH}$ = 0	
	=	$K_e * B * f_e * I_s * F3_{FGC}$	
	=	0 lb/year	FGC is not present
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13 (Eqn 4-12)
	=	$K_s * B * f_{sreagent} * S_{NH3}$	
where	K_s =	Conversion factor	
	=	3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-13 (Eqn 4-13)
	B =	Coal burn, Tbtu/yr	Cleco data
	=	49.93 TBtu/yr (average for '12-'14)	4-13 (Eqn 4-12)
	$f_{sreagent}$ =	fraction of SCR operation wih reagent injection	4-7 (Eqn 4-6)
	=	f_{sops} = 0.43 unitless (for seasonal operation)	SNCR is present
	S_{NH3} =	NH_3 slip from SCR/SNCR, ppmv at 6% O2	4-13 (Eqn 4-12)
	=	5 ppmv (SNCR average, presented in Eqn 4-12)	
	=	407837.0862 lb/year	
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14 (FGC not present)
	=	$NH3_{FGC\_beforeAPH}$ $NH3_{FGC\_afterAPH}$ = 0	
	=	$K_e * B * f_e * I_{NH3}$	
	=	0 lb/year No FGC is present	
$F2_x$	=	Technology impact factors for processes downstream of the APH (sum of all that apply)	4-12
	=	0.63 for hot-side ESP	4-20 (Table 4-4 for hot-side ESP)

Notes:

1. Unit 2 is a dry-bottom, wall-fired boiler that burns PRB coal (currently with a sulfur equivalent to 0.55 lbs SO_2/MMBtu) with an ESP (hot-side). There is no flue gas conditioning for PM.
2. Ammonia solution is injected through the SNCR during the ozone season, but it is injected downstream of the ESP.
3. Unit 2 has been retrofitted with: LNB (installed several years ago), SNCR, and DSI.
4. Unit 2 has an air preheater.
5. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.

Cleco, Rodemacher II (Unit 2 w/DSI + FF)

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

assumes heating value of 8,757 Btu/lb and a sulfur content of 0.45 % and an ash content of 5.53 % and a heat input o 6,534 mmBtu/hr and FGD penetration factor = 0.01

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0263	0.0063	0.0032	0.6	0.0032	0.0030	1	0.00012	10	**0.020**	0.000	SO4	3*f(RH)	0.020	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.461	**0.111**	0.055	0.6	**0.055**	0.053	1	0.0020	10	0.350	0.003	SO4	3*f(RH)	0.347	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	24.0%	12.0%	0.6	12.0%	11.6%	1	0.4%	10	76.0%	0.6%	SO4	3*f(RH)	75.4%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**189.6**	45.5	22.7	0.6	22.7	21.9	1	0.8	10	144.1	1.2	SO4	3*f(RH)	142.9	SOA	4

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		0.00 lb/hr	(SO_4)

Redistribute remainder of total PM_{10}: 189.6 lb/hr

Coarse	12.1%	22.89 lb/hr	(PMC)
Fine Soil	11.6%	22.04 lb/hr	(PMF)
Fine EC	0.4%	0.85 lb/hr	(EC)
CPM OR	75.9%	143.82 lb/hr	(SOA)

EPRI, ***Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)***, **March 2012**

TSAR = Total sulfuric acid (H_2SO_4) release, lbs/yr

$= \{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$

= -228,687.19 lb/year

where:

EM_{Comb} = H_2SO_4 manufactured from combustion, lbs/yr
= K * F1 * E2
= 98,800.35 lb/year

where K = Units conversion factor
= 3063 lb H_2SO_4/ton SO_2

F1 = Fuel Impact Factor (PRB coal, all boiler types)
= 0.0019 *unitless*

E2 = SO_2 emission rate, tons/yr
= 16,976.88 tons/yr (max. day during '12-'14)

Cleco, Rodemacher II (Unit 2 w/DSI + FF)

EPRI (Continued)

EM_{SCR} = H_2SO_4 manufactured from SCR
= 0 lb/year

EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning
= $EM_{FGC\_beforeAPH}$ $\quad$ $EM_{FGC\_afterAPH}$ = 0
= $K_e * B * f_e * I_s * F3_{FGC}$
= 0 lb/year

$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR
= $K_s * B * f_{sreagent} * S_{NH3}$

where K_s = Conversion factor
= 3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)
B = Coal burn, Tbtu/yr
= 49.93 TBtu/yr (average for '10-'14)
$f_{sreagent}$ = fraction of SCR operation wih reagent injection
= f_{sops} = 0.43 unitless (for seasonal operation)
S_{NH3} = NH_3 slip from SCR/SNCR, ppmv at 6% O2
= 5 ppmv (SNCR average, presented in Eqn 4-12)
= 407837.086 lb/year

$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive
= 0.36 for air heater

$NH3_{FGC}$ = Ammonia produced from FGC
= $NH3_{FGC\_beforeAPH}$ $\quad$ $NH3_{FGC\_afterAPH}$ = 0
= $K_e * B * f_e * I_{NH3}$
= 0 lb/year $\quad$ No FGC is present

$F2_X$ = Technology impact factors for processes downstream of the APH (sum of all that apply)
= 0.63 for hot-side ESP
= 0.1 for baghouse
= 0.01 for dry FGD and baghouse
= 0.74 sum of all factors

$TSAR_{ALKINJ}$ = $(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$
$TSAR_{Comb+SCR+FGC}$ = -228,687.19 lb/year
$F3_{ALKINJ}$ = 0.2 expected fractional reduction in SO3, default is 0.2.
= -45737.437 lb/year

Total TSAR = $(TSAR_{Comb+SCR+FGC}) + (TSAR_{ALKINJ})$
= -274,424.62 lb/year

Notes:
1. Unit 2 is a dry-bottom, wall-fired boiler that burns PRB coal (currently with a sulfur equivalent to 0.55 lbs SO_2/MMBtu) with an ESP (hot-side). There is no flue gas conditioning for PM.
2. Ammonia solution is injected through the SNCR during the ozone season, but it is injected downstream of the ESP.
3. Unit 2 has been retrofitted with: LNB (installed several years ago), SNCR, and DSI.
4. Unit 2 has an air preheater.
5. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
6. FGD penetration factor of 0.01 (EPRI, Table 4-4) was incorporated into the NPS workbook. TSAR for alkali injection was incorporated into the EPRI SO4 calculation. Per Don Shepherd at NPS (email dated 10/13/15)

Cleco, Rodemacher II (Unit 2 w/DFGD)

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions contro

assumes heating value of 8,757 Btu/lb and a sulfur content of 0.45 % and an ash content of 5.53 % and a heat inpu 6534 mmBtu/hr and f(RH) = 1

	Controlled PM10 Emissions (Bold values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0263	0.0063	0.0032	0.6	0.0032	0.0030	1	0.00012	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (Bold Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.461	**0.111**	0.055	0.6	**0.055**	0.053	1	0.0020	10	0.350	0.280	SO4	3*f(RH)	0.070	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	24.0%	12.0%	0.6	12.0%	11.6%	1	0.4%	10	76.0%	60.8%	SO4	3*f(RH)	15.2%	SOA	4

If you are given Total PM10 emissions in lb/hr

	Controlled PM10 Emissions (Bold Value is Input by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	189.6	45.5	22.7	0.6	22.7	21.9	1	0.8	10	144.1	115.3	SO4	3	28.8	SOA	4

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR		0.00 lb/hr	(SO_4)
Redistribute remainder of total PM_{10}:		189.6 lb/hr	
Coarse	30.6%	58.04 lb/hr	(PMC)
Fine Soil	29.5%	55.89 lb/hr	(PMF)
Fine EC	1.1%	2.15 lb/hr	(EC)
CPM OR	38.8%	73.52 lb/hr	(SOA)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790*, , March 2012

TSAR = Total sulfuric acid (H_2SO_4) release, lbs/yr

= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$

= -251,716.88 lb/year

where:

EM_{Comb} = H_2SO_4 manufactured from combustion, lbs/yr

= K * F1 * E2

= 14,529.46 lb/year

where K = Units conversion factor

= 3063 lb H_2SO_4/ton SO_2

F1 = Fuel Impact Factor (PRB coal, all boiler types)

= 0.0019 *unitless*

E2 = SO_2 emission rate, tons/yr

= 2,496.60 tons/yr (max. day during '10-'14)

Cleco, Rodemacher II (Unit 2 w/DFGD)

EPRI (Continued)

EM_{SCR} = H_2SO_4 manufactured from SCR
= 0 lb/year

EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning
= $EM_{FGC\_beforeAPH}$ $EM_{FGC\_afterAPH}$ = 0
= $K_e * B * f_e * I_s * F3_{FGC}$
= 0 lb/year

$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR
= $K_s * B * f_{sreagent} * S_{NH3}$

where K_s = Conversion factor
= 3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)
B = Coal burn, Tbtu/yr
= 49.93 TBtu/yr (average for '10-'14)
$f_{sreagent}$ = fraction of SCR operation wih reagent injection
= f_{sops} = 0.43 unitless (for seasonal operation)
S_{NH3} = NH_3 slip from SCR/SNCR, ppmv at 6% O2
= 5 ppmv (SNCR average, presented in Eqn 4-12)
= 407837.086 lb/year

$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive
= 0.36 for air heater

$NH3_{FGC}$ = Ammonia produced from FGC
= $NH3_{FGC\_beforeAPH}$ $NH3_{FGC\_afterAPH}$ = 0
= $K_e * B * f_e * I_{NH3}$
= 0 lb/year   No FGC is present

$F2_X$ = Technology impact factors for processes downstream of the APH (sum of all that apply)
= 0.63 for hot-side ESP
= 0.01 for dry FGD and baghouse
= 0.64 total F2 factors

Notes:
1. Unit 2 is a dry-bottom, wall-fired boiler that burns PRB coal (currently with a sulfur equivalent to 0.55 lbs SO/MMBtu) with an ESP (hot-side). There is no flue gas conditioning for PM.
2. Ammonia solution is injected through the SNCR during the ozone season, but it is injected downstream of the ESP
3. Unit 2 has been retrofitted with: LNB (installed several years ago), SNCR, and DSI
4. Unit 2 has an air preheater.
5. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012

Cleco, Rodemacher II (Unit 2 w/ WFGD)

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-7
Wet Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

assumes heating value of 8757 Btu/lb and a sulfur content of 0.45 % and an ash content 5.53 % and a heat in 6534 mmBtu/hr and f(RH) = 1

	Controlled PM10 Emissions (**Bold values from Table 1.1-5.**)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-WB	0.0333	0.0133	0.0063	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold Values from Table 1.1-7.**)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-WB	0.583	**0.232**	0.111	0.6	**0.122**	0.117	1	0.005	10	0.350	0.280	SO4	3*f(RH)	0.070	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-WB	100%	39.9%	19.0%	0.6	20.9%	20.1%	1	0.8%	10	60.1%	48.1%	SO4	3*f(RH)	12.0%	SOA	4

If you are given Total PM10 emissions in lb/hr

	Controlled PM10 Emissions (**Bold Value is Input by user.**)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-WB	189.6	75.6	36.0	0.6	39.6	38.1	1	1.5	10	114.0	91.2	SO4	3	22.8	SOA	4
		Weighted Extinction		21.6			38.1		14.7				273.6			91.2

2.3

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).

CMP IOR 0.00 lb/hr (SO_4)

Redistribute remainder of total PM_{10}: 189.6 lb/hr

Coarse	36.6%	69.36 lb/hr	(PMC)
Fine Soil	38.8%	73.48 lb/hr	(PMF)
Fine EC	1.5%	2.82 lb/hr	(EC)
CPM OR	23.2%	43.94 lb/hr	(SOA)

TSAR = Total sulfuric acid (H_2SO_4) release, lbs/yr

$= \{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$

= -409,596.46 lb/year

where:

EM_{Comb} = H_2SO_4 manufactured from combustion, lbs/yr
= K * F1 * E2
= 10,170.62 lb/year

where K = Units conversion factor
= 3063 lb H_2SO_4/ton SO_2
F1 = Fuel Impact Factor (PRB coal, all boiler types)
= 0.0019 *unitless*
E2 = SO_2 emission rate, tons/yr
= 1,747.62 tons/yr (max. day during '10-'14)

Cleco, Rodemacher II (Unit 2 w/ WFGD)

EPRI (Continued)

EM_{SCR} = H_2SO_4 manufactured from SCR
= 0 lb/year

EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning
= $EM_{FGC\_beforeAPH}$ $EM_{FGC\_afterAPH}$ = 0
= $K_e * B * f_e * I_s * F3_{FGC}$
= 0 lb/year

$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR
= $K_s * B * f_{sreagent} * S_{NH3}$

where K_s = Conversion factor
= 3799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)
B = Coal burn, Tbtu/yr
= 49.93 TBtu/yr (average for '10-'14)
$f_{sreagent}$ = fraction of SCR operation wih reagent injection
= f_{sops} = 0.43 unitless (for seasonal operation)
S_{NH3} = NH_3 slip from SCR/SNCR, ppmv at 6% O2
= 5 ppmv (SNCR average, presented in Eqn 4-12)
= 407837.09 lb/year

$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive
= 0.36 for air heater

$NH3_{FGC}$ = Ammonia produced from FGC
= $NH3_{FGC\_beforeAPH}$ $NH3_{FGC\_afterAPH}$ = 0
= $K_e * B * f_e * I_{NH3}$
= 0 lb/year No FGC is present

$F2_X$ = Technology impact factors for processes downstream of the APH (sum of all that apply)
= 0.63 for hot-side ESP
= 0.4 for wet spray tower (PRB coal)
= 1.03 total F2 factors

Notes:
1. Unit 2 is a dry-bottom, wall-fired boiler that burns PRB coal (currently with a sulfur equivalent to 0.55 lbs SO/MMBtu) with an ESP (hot-side). There is no flue gas conditioning for PM.
2. Ammonia solution is injected through the SNCR during the ozone season, but it is injected downstream of the ESP
3. Unit 2 has been retrofitted with: LNB (installed several years ago), SNCR, and DSI
4. Unit 2 has an air preheater.
5. SO4 emissions are calculated using the EPRI Method, as outlined in the reference document
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012

APPENDIX C: MODELING FILES

To be submitted via email.